Emissions Markets

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Learning Objectives

After completing this reading, you should be able to

- Compare systems to price pollution from power generators, including emissions charges, and emissions markets (including cap-and-trade systems)
- Describe the impact of imposing a price on emissions on different types of power generators and on the merit order
- Apply the carbon emissions factor and calculate the marginal cost and profitability of a power generator when emissions are priced
- Describe and calculate the clean spark spread and the clean dark spread
- Explain factors and emissions market elements that can impact the price of carbon allowances in a cap-and-trade system
- Explain policies and market structures designed to encourage production from non-carbon emitting generators

Excerpt is Chapter 9 of Introduction to Electricity Markets, *by John Parsons.*

Chapter 9

Emissions Markets

9.1 Introduction

The various generation technologies available to us come with a variety of potentially harmful impacts on our environment and on human health. These impacts are very diverse, and that diversity shapes the design of government policies and regulations. Different categories of potentially adverse impacts include:

- Emissions of various chemicals into the air, which are perhaps the most familiar category. Some examples of these are as follows:
  - Carbon dioxide (CO_2) – Burning any fossil fuel produces CO_2, which is one of the greenhouse gases that contributes to global warming and climate change.
  - Sulfur dioxide (SO_2) – Burning coals and oil products containing sulfur produces SO_2, which is harmful to human health and to ecosystems. High concentrations of SO_2 in the atmosphere also contributes to creating particulate matter (PM), which in turn is harmful to human health and creates the haze that reduces visibility.
  - Nitrogen oxides (NO_x) – Burning any fossil fuel produces NO_x, including both nitric oxide (NO) and nitrogen dioxide (NO_2), which are harmful to human health and also contribute to creating PM. Together with volatile organic compounds (VOCs), NO_x reacts with sunlight to produce ground level ozone, which is harmful to human health and to ecosystems.
  - Incomplete combustion of fossil fuels also directly produces PM.
  - Burning of coals and oil products containing mercury can release it into the air and ultimately into the food chain, which is harmful to human health.
  - Incineration of waste to produce power produces many of these emissions, too, as well as other dangerous chemicals.
- Accumulation of waste is another category of potentially harmful impacts. For example, coal ash must be carefully handled, stored and eventually disposed of. The same is true of the spent fuel from nuclear reactors.
- The heat in warmed cooling water that flows into river or coastal ecosystems is another important source of potentially negative environmental impacts from many types of power generation.
- In addition, certain technologies have other particularly unique considerations.
  - The operation of hydro power plants has a significant impact on the ecology of a river basin and must be managed accordingly.
  - The operation of nuclear reactors poses the danger of accidental release of radioactive materials.

  - The production, transportation and storage of natural gas (methane, CH_4) must be managed to prevent release to the atmosphere, since methane is a potent greenhouse gas.

From an economic standpoint, pollution challenges the effectiveness of relying on market prices to incentivize the right production decisions. A company's profit calculation weighs the price earned for its product against the costs the company must pay to produce it. The cost of equipment, of labor, of fuel and so on, for which a company must pay are called **private costs** for its product. In contrast, the damage from pollution is felt by others, whether residents living in the vicinity of a plant, or a larger population living downwind and downstream, or a very dispersed population around the globe. These are the **public costs** or the **social costs** for its product. The problem comes in the fact that the social cost is usually an **externality**: it is external to a company's profit calculation. When social costs are externalities, the company's profit calculation does not adequately incorporate all of the costs of its decisions, it is therefore likely to make the wrong decision and produce too much pollution. Society must act to enforce better decisions.

Indeed, governments impose a variety of mandates and prohibitions to restore a better outcome in which harmful pollution is minimized. These can include mandating specific types of investments that reduce emissions. For example, certain regions or countries mandate the use of equipment that captures sulfur before it is released. Many regions or countries restrict the types of fuels that can be used, in order to avoid certain types of emissions entirely. Some mandate minimum levels of operating efficiency, which lowers the pollution per unit of output. Some regions or countries mandate investments in certain generating technologies because they produce less of the most dangerous pollutants, although every technology involves some environmental compromise. Often, operating licenses for power plants place strict limits on the release of heat or other pollutants.

Governments also have available to them other mechanisms, besides mandates and prohibitions, to incentivize reductions in emissions. We review those here.

9.2 Pricing Pollution

One important mechanism is pricing pollution. The objective is to **internalize** the social cost: that is, to force the company to pay a monetary cost for the pollution so that the company's profit calculation better reflects society's full interest.

9.2.1 An Emissions Charge or an Emissions Market

A direct way to price pollution is to assess an **emissions charge** (or fee or tax or levy). As far back as the early 1990s, several European countries introduced carbon taxes to incentivize reductions in CO_2 emissions. More recently, in 2008, the Canadian province of British Columbia introduced its carbon tax system. Figure 9.1 shows the legislated price on carbon in British Columbia, which was initially set at C\$10/tCO_2 and increased to C\$30 in 2012, where it remains today.[1] In 2017, the federal government of Canada announced a plan to impose a carbon tax on emissions in any province that did not impose its own comparable measure.

An alternative way to price pollution is to establish an **emissions markets** like the **European Union's Emissions Trading System** (EU-ETS).[2] In this system, the government determines a **cap** on the total amount of allowed emissions in a region and requires companies in specified sectors operating in the region to purchase tradable permits or allowances sufficient to cover their emissions–hence such systems are also known as **cap-and-trade systems**. In the EU-ETS, one allowance is valid for one metric ton of CO_2. Figure 9.2 shows the annual cap starting in 2005 and projected through 2050.[3] In the EU-ETS, most allowances

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[1] CO_2 charges are almost universally denominated in metric tons which we abbreviate simply as t.

[2] A good guide to the establishment and early years of the EU-ETS is Ellerman, A. Denny, Frank Convery and Christian de Perthuis, Pricing Carbon: the European Emissions Trading Scheme, Cambridge University Press, 2010.

[3] Throughout the short history of the EU-ETS, coverage has expanded significantly. It has been extended to incorporate more sectors, such as the aviation sector, and to include more countries, such as when the EU expanded to incorporate eastern European countries. Consequently, for a time series to be a useful comparison across time, it may be restricted in one way or another: for example, Figure 9.2 does not include allowances allotted for aviation.

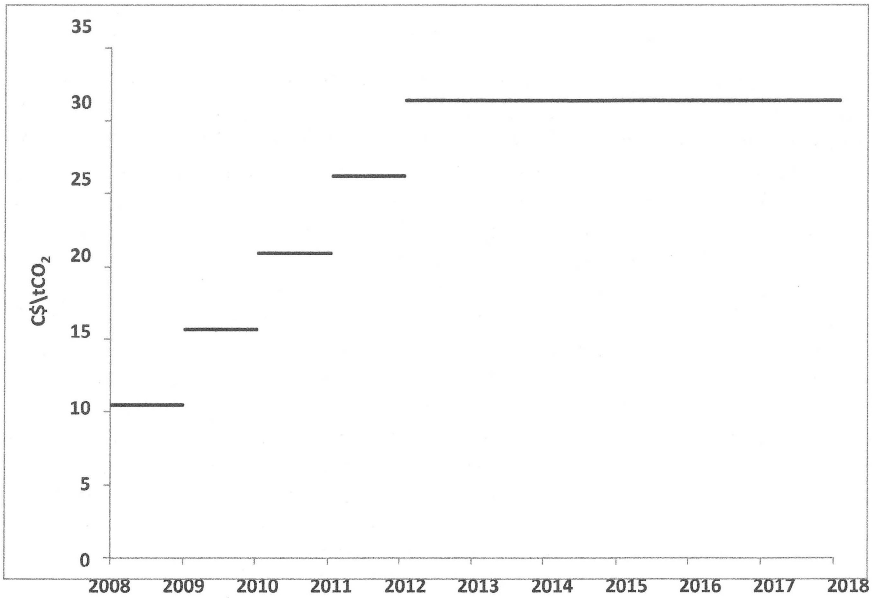

Figure 9.1: The Carbon Tax Rate in British Columbia, 2008-2017.

Data source: British Columbia Ministry of Environment and Climate Change Strategy, www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/carbon-tax

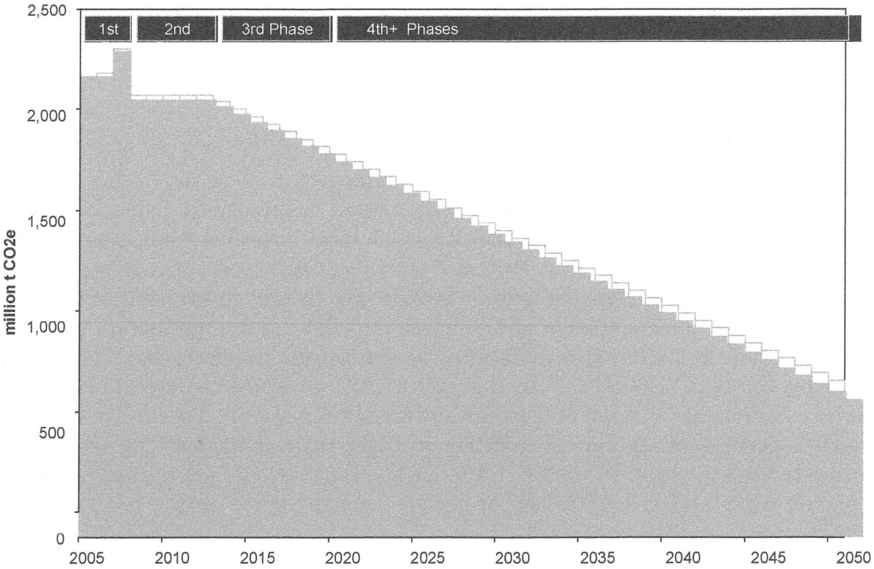

Figure 9.2: The EU-ETS's Annual CO_2 Emissions Cap, 2005-2050.

Data source: European Environment Agency, "Perspective of the EU ETS cap up to 2050."

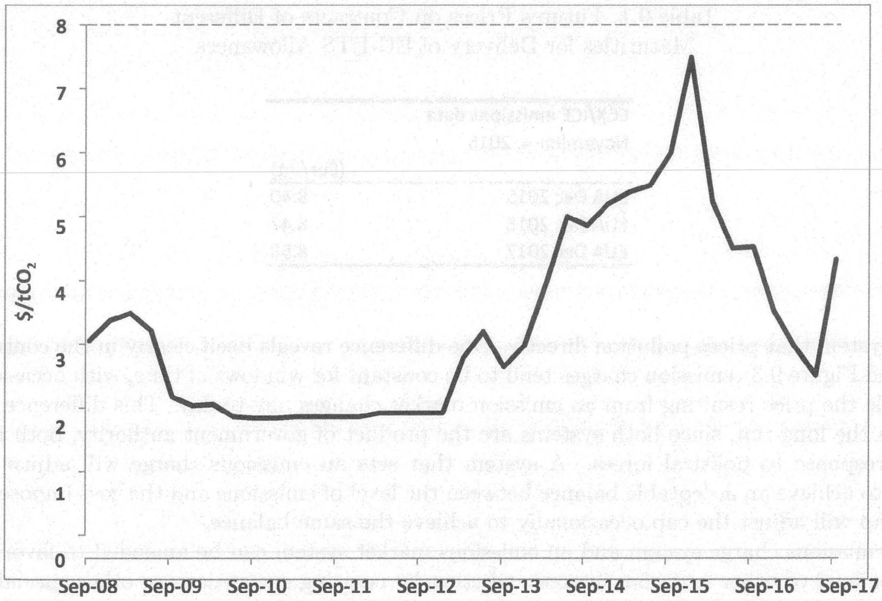

Figure 9.3: Auction Clearing Prices for RGGI CO_2 Allowances, 2008-2017.

Data source: Regional Greenhouse Gas Initiative, Inc. (RGGI).

are now distributed through auctions in which firms compete to buy allowances. These auctions are called the **primary market**. Allowance holders can also trade allowances among themselves. This trade is called the **secondary market**. If the firm's emissions exceed its stock of allowances, it can go into the secondary market to purchase more. Alternatively, if the firm's emissions are less than its stock of allowances, it can sell them.

Markets have been used for a variety of emissions. Indeed, the U.S. first employed emissions markets in the 1990s to address power plant emissions of SO_2 and NO_x, and only recently have CO_2 emissions become the focus. While the EU-ETS initially focused only on CO_2, it has been expanded to include emissions of nitrous oxide and perfluorcarbons, which are also greenhouse gases.[4] Carbon markets have been employed in many regions and countries, including New Zealand, parts of the United States, and most recently in some pilot projects in provinces of China. The Chinese government has announced plans to extend its CO_2 emissions trading systems nationwide, although how this will proceed is still uncertain.

Emission markets establish a price on pollution indirectly, by fixing the supply of allowances and letting market demand determine a clearing price. Figure 9.3 shows the fluctuating clearing price for emission allowances in the RGGI system that covers power plant emissions in nine states in the northeastern U.S.. An emission market also opens up the possibility of trade in futures contracts for allowances. Table 9.1 shows prices for three successive futures contracts on European Union Allowances (EUAs) quoted on the European Climate Exchange (ECX) as reported by Platts. The table displays the contracts for December delivery, which are the benchmark liquid contracts.

A system that prices pollution indirectly, through the establishment of an emissions market, is very

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[4] The greenhouse effect is caused by several different gases, including CO_2, but also methane, nitrous oxide, and perfluorcarbons–aka the greenhouse gases. An EU-ETS allowance is defined to give the holder the right to emit one ton of CO_2 or the 'equivalent' of certain other gases, where the equivalence is defined in the rules of the EU-ETS based on the science of the greenhouse effect and other matters. Consequently, the price of an allowance is quoted in terms of €/tCO_2e, meaning CO_2 equivalent. To keep our exposition simple, we focus exclusively on CO_2 and refer to the price of an allowance in terms of €/tCO_2.

Table 9.1: Futures Prices on Contracts of Different Maturities for Delivery of EU-ETS Allowances

ECX/ICE emissions data November 4, 2015	(Eur/mt)
EUA Dec 2015	8.40
EUA Dec 2016	8.47
EUA Dec 2017	8.58

similar to a system that prices pollution directly. One difference reveals itself clearly in the contrast between Figure 9.1 and Figure 9.3: emission charges tend to be constant for windows of time, with occasional discrete changes, while the price resulting from an emission market changes day-to-day. This difference holds in the short-run. In the long-run, since both systems are the product of government authority, both are regularly adjusted in response to political forces. A system that sets an emissions charge will adjust that charge occasionally to achieve an acceptable balance between the level of emissions and the cost imposed. A system that sets a cap will adjust the cap occasionally to achieve the same balance.

Both an emissions charge system and an emissions market system can be amended to favor a particular industrial, regional or other sectarian interest, whether by creating exemptions or other special terms. The two systems can also be hybridized. For example, an emissions market system can be amended to include a specified price floor. In this case, whenever the demand for allowances is below a certain threshold, the quantity issued is effectively reduced so that the price remains above the floor. Whenever the price floor is binding, the system looks more like a pure emissions charge, and whenever the floor is not binding, it looks more like a pure emissions market. Indeed, the RGGI system is a market with such a floor, and the price shown in Figure 9.3 for 2009-2013 clearly reflects the floor which was in the neighborhood of \$2.00/tCO_2.

9.2.2 Impact of Pricing Pollution on the Marginal Cost of Electricity

Putting a price on emissions internalizes the externality. Without the price, CO_2 emissions are a cost to society, but not one that the owner of the power plant takes into account when bidding to supply power or when choosing how to operate and maintain its plant. With the price, this becomes a cost to the owner of the power plant, and now the owner will take that cost into account when deciding how to sell and how to operate and maintain its plant.

Table 9.2 shows how an emissions charge changes the marginal cost of four different fossil fuel-fired power plants. The columns of the table each present the calculations for a different plant. The first two are both fueled with natural gas: one is a combined-cycle plant and the other is a combustion turbine. The second two are both steam turbine plants: one is fueled with bituminous coal and the other with lignite. The first row shows the fuel price for each power plant. The prices shown are all expressed in terms of the MWh of heat content of the fuel. This is how natural gas usually trades in Europe. In contrast, coal prices are often quoted in terms of metric tons, and this must be translated to a price per unit of heat based on the heat content of the particular coal.[5] The second row is the thermal efficiency of each plant. The third row is the marginal cost per unit of electricity generated. Looking at the natural gas-fired combined cycle plant, we see a price of natural gas of €17.05/MWh. Since the plant has a 48% efficiency, this translates to a fuel cost of €35.52/MWh of electricity produced. As we noted in Chapter 3, this marginal fuel cost is the dominant element of the marginal operating cost of a fossil fuel-fired power plant when there is no emissions charge. Note that in our example, the lignite power plant has the lowest marginal fuel cost, followed by the

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[5] There is an active market for bituminous coal, with widely used benchmark prices and conventions for adjusting these to account for delivery to different generators. On the other hand, lignite coal is not widely traded, and there is no widely accepted benchmark price. Generators that use lignite usually source it locally under long-term arrangements that may include integration between the mine and the generator. Therefore, the fuel price shown for lignite is most likely the owner's estimate of its marginal cost.

Table 9.2: The Impact of Emissions Charges on the Marginal Cost of Four Different Power Plants

		Natural Gas Combined Cycle	Natural Gas Combustion Turbine	Coal (Bituminous) Steam Turbine	Coal (Lignite) Steam Turbine
Fuel price	(€/MWh)	17.05	17.05	11.00	9.30
Thermal efficiency		48%	30%	35%	32%
Marginal fuel cost	(€/MWh)	35.52	56.83	31.43	29.06
Emissions price	(€/tCO2)	11.00	11.00	11.00	11.00
Carbon content of fuel	(tCO2/MWh)	0.2012	0.2012	0.3370	0.4003
Carbon emissions factor	(tCO2/MWh)	0.4193	0.6708	0.9627	1.2510
Marginal emissions cost	(€/MWh)	4.61	7.38	10.59	13.76
Marginal fuel + emissions cost	(€/MWh)	40.13	64.21	42.02	42.82

bituminous coal plant, followed by the natural gas-fired combined cycle plant. The combustion turbine has the highest marginal cost, due to its low efficiency.

The next four rows of the table show how a CO_2 emissions price is translated into a marginal cost of emissions. In our example, this price is set equal to €11.00/tCO_2 and is the same for each of the plants. To translate this into a cost per unit of electricity produced, we need to determine the amount of CO_2 produced at each plant per unit of electricity, which is the **carbon emissions factor** for each plant. The factor has two components: (i) the carbon content of the fuel, and (ii) the plant's efficiency in producing electricity, i.e., the thermal efficiency. The carbon content of each fuel is shown in the fifth row of the table. Since the same natural gas is used in the two natural gas-fired plants, they have the same carbon content of fuel. The carbon content of bituminous coal is higher, and the carbon content of the lignite coal is higher still. The carbon emissions factor is calculated by dividing the carbon content of the fuel by the thermal efficiency, and is shown in the sixth row. To produce 1 MWh of electricity, a plant that has a 48% thermal efficiency, such as the combined cycle plant in the table, must burn fuel with a little more than twice as much thermal energy. Therefore, the plant has a carbon emissions factor measured in metric tons of CO_2 per MWh of electricity that is more than twice the carbon emissions measured in metric tons of CO_2 per MWh of thermal energy: 0.4193 versus 0.2012.[6] The two plants fueled with natural gas have the same carbon content in their fuel, but the combustion turbine has a lower thermal efficiency and therefore must burn more of the fuel for every MWh of electricity produced. It therefore has a higher final power plant emissions factor. The lignite coal has a higher carbon content than the bituminous coal, which is the main factor behind the lignite plant having a higher emissions factor as compared to the bituminous plant. The seventh row shows the marginal emissions cost, which is the emissions price multiplied by the emissions factor.

The last line sums the marginal fuel cost and the marginal emissions cost: for the natural gas-fired combined-cycle plant, the marginal fuel plus emissions cost is €40.13/MWh. Note that when we take into account the emissions charge, the ranking of the four plants by total marginal fuel plus emissions cost is different: now the combined-cycle plant has the lowest marginal cost, followed by the bituminous coal plant, followed by the lignite plant. The combustion turbine plant still has the highest marginal cost.

In the short-run, pricing emissions induce many changes in how the electricity system is operated. Some of these changes are described as follows:

- A shift in the merit order among generators, like the one shown in Table 9.2, is one of the most important short-run drivers of emission reductions. Generators with high emissions factors should now clear the market less often so that their utilization declines. Generators with low emissions factors should clear the market more often so that their utilization increases. As a result of this shift in the merit order, the average level of emissions per unit of electricity generated in the region or country declines.

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[6] Note that the MWh referred to in the third and fifth rows of the table refer to units of heat or thermal energy, whereas the MWh referred to in the first, sixth, seventh and eighth rows refers to units of electricity.

- A price on pollution can also incentivizes a generator to switch the fuel it uses. This is especially true with regard to controlling SO_2 emissions, where generators can specifically purchase low sulfur coal or low sulfur oil. Of course, lower sulfur fuels are typically priced higher, and so it is only worth shifting to the low sulfur fuel if the emissions charge savings are large enough.
- A price on pollution also adjusts other components of a generator's operating cost. In particular, the hit to efficiency from cycling a plant up and down becomes more costly. So plant operators adjust their bids accordingly. In this way, the price re-shapes how plants are operated.
- A price on pollution also raises the equilibrium wholesale price of electricity. This higher price of electricity should translate into a lower quantity of electricity consumed, which also reduces emissions.

In the longer-run, a price on pollution also incentivizes different types of investments which reduce the emissions factor.

- In our example of a price on CO_2, technologies which do not emit CO_2, such as nuclear or renewables, will earn a higher equilibrium market price for the electricity they generate while having no increase in cost. Therefore, a new investment in these technologies should appear more profitable than had there been no price on CO_2. Technologies with a high emissions factor, such as lignite coal, will be idle more often and the per unit operating profit when they do run will be less. Therefore, a new investment in these technologies should appear less profitable than had there been no emissions charge.
- In the case of a SO_2 emissions charge, the owner of a coal-fired generator may be incentivized to invest in equipment that can capture the sulfur, thereby preventing emissions to the air and avoiding an emissions charge. In the case of CO_2, investments in carbon capture are also possible, but have not yet had any significant take-up.
- In all cases, a generation owner can invest in upgrades to their plant that boost the thermal efficiency, which reduces the amount of fuel burned per unit of electricity, and thereby also reduces emissions per unit of electricity. Investors in new generation are incentivized to select the more thermally efficient variant of any technology.

The advantage of putting a price on emissions–as opposed to imposing a technology mandate–is that plant owners decide on a case-by-case basis which sort of short-run operating decisions and long-run investment in emissions reduction is the most cost effective. The validity of this advantage depends on details about how the specific harmful impacts from emissions occur, as well as on many details about how the emissions charge is set and levied. The effectiveness of an emissions charge depends upon the larger regulatory and market structure. In particular, it depends upon how the polluting company's output price is determined–in our case, that means the wholesale electricity price.

To make this last point concrete, consider two alternative electricity market structures:

- The first is a competitive wholesale market in which the lowest bidding generators are dispatched, and there is a single system clearing price for energy, with adjustments made for losses and congestion. Each generator's realized rate of profit is different, reflecting its own cost.
- The second is a rate-of-return regulated system, in which the lowest operating cost generators are dispatched, and the system price is set to recover total operating and capital cost, plus an allowed rate of profit. Each generator's realized rate of profit is the same.

Charging a price for pollution has very different consequences in the two markets.

- If the electricity price is set in a competitive market, then the emissions charge effectively internalizes the cost. To see this, consider two generators producing the same quantity of electricity in the same hour, but with one generator having a higher carbon emissions factor than the other. They both receive the same price for their product, but the one with the higher emissions factor will have a higher cost and therefore a lower unit profit.
- In contrast, if the electricity price is set to reflect generators' costs, including the price paid for emissions, then the emissions charge does not effectively internalize the cost. In this case, our two generators, receive different prices for selling the same product, so that the generator with the higher emissions factor has the same unit profit as the generator with the lower emissions factor.

The bullets above itemized two simple alternatives for a regulatory and market structure. In practice, there are many different shades of gray. The full details of the regulatory and market structure are necessary to determine how completely the price put on pollution effectively internalizes an externality.[7]

The effectiveness of a cap-and-trade system also depends upon the larger regulatory and market structure, just as does the effectiveness of an emissions charge system. The allocation of allowances is often a key variable.

- In the early years of the EU-ETS, almost all allowances were distributed for free to the incumbent generators and other covered entities based on historical emissions, which is known as grandfathering. Despite this free allocation, generators were allowed to sell their allowances. Therefore, although they received allowances for free, the opportunity cost of emissions equaled the secondary market price for allowances: every extra ton of emissions was one less allowance that could be sold. As the EU-ETS has progressed, the system has shifted so that nearly all of the allowances are sold in auctions.
- Sometimes a set of allowances is reserved to be distributed to targeted companies. For example, the EU-ETS set aside some allowances to be distributed to new entrants, such as newly constructed plants. In addition, the rules also made it possible to 'claw back' free allowances from grandfathered plants that chose to shut down instead of operating. The granting of free allowances can undo some of the incentive effects of the market in allowances if it is contingent on future investment or operating decisions. For example, consider a company evaluating investment in either a new coal-fired power plant, for which it will be awarded free allowances, or a non-emitting technology such as a wind or nuclear plant. The free allocation improves the profitability of an investment in this technology with a high emissions factor relative to an alternative investment in a zero emissions technology.

9.2.3 Clean Spreads

Table 9.2 showed how a price on CO_2 increased the marginal operating cost of fossil fuel-fired generators. Where emissions allowances are traded, the size of the increase fluctuates with the price of allowances, and the total level is a function of both the fuel cost and the allowance cost. In Chapter 6, we defined the spark and dark spreads and noted their importance for the management of natural gas- and coal-fired power plants. Where allowances are required, it is not enough for a generator to earn a positive spark or dark spread. It must also earn enough to pay for the required allowances. This leads us to the concept of a **clean spread**. For a natural gas-fired generator, the relevant clean spread is the **clean spark spread**:

$$\text{clean spark spread } \left(\frac{€}{\text{MWh}}\right) = \text{spark spread } \left(\frac{€}{\text{MWh}}\right) - \text{cost of emissions allowances } \left(\frac{€}{\text{MWh}}\right) \quad (9.1)$$

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[7] Do not confuse the competitive equilibrium effect of an emissions charge with the incentive effect for an individual generator. In a competitive equilibrium, an emissions charge causes the equilibrium market price to increase. But, for an individual generator, there is no automatic pass through of its own emissions charges. That is, in a competitive market, a generator with a high emissions factor cannot charge a higher price than a generator with a low emissions factor. While an emissions charge causes a higher equilibrium market price, the generator with the high emissions factor will lose market share and be less profitable.

Table 9.3: Clean Spreads Calculated for Four Different Power Plants

		Natural Gas Combined Cycle	Natural Gas Combustion Turbine	Coal (Bituminous) Steam Turbine	Coal (Lignite) Steam Turbine
Electricity price	(€/MWh)	41.93	41.93	41.93	41.93
Marginal fuel cost	(€/MWh)	35.52	56.83	31.43	29.06
Spread	(€/MWh)	6.41	-14.90	10.50	12.87
Marginal emissions cost	(€/MWh)	4.61	7.38	10.59	13.76
Clean spread	(€/MWh)	1.80	-22.28	-0.09	-0.89

For a coal-fired generator, it is the **clean dark spread**:

$$\text{clean dark spread } (\frac{€}{\text{MWh}}) = \text{dark spread } (\frac{€}{\text{MWh}}) - \text{cost of emissions allowances } (\frac{€}{\text{MWh}}) \tag{9.2}$$

Table 9.3 shows the calculation of clean spreads for our four power plants. The first row is the price of electricity, which in any given hour or for any block of hours on any given day is assumed to be the same for all four plants. The second row shows the marginal fuel cost, which we had calculated earlier based on the fuel price and the plant's thermal efficiency. The difference between the top two rows is the spread. For our natural gas-fired plants, this is a spark spread, while for our coal-fired plants, these are different dark spreads. The fourth row is the marginal emissions cost, which we had calculated earlier based on each plant's carbon emissions factor and the price of an allowance. The final row is the clean spread. For our natural gas-fired plants, this is a clean spark spread, while for our coal-fired plants, these are different clean dark spreads.

Clean spreads vary with (i) the price of electricity, (ii) the price of fuel, and (iii) the price of emissions allowances. The impact of an increase in the price of electricity is simple: a €1/MWh increase in the price of electricity increases both all clean spreads equally, whether clean spark or clean dark spreads. The direct impact of an increase in the price of either fuel or of the price of emissions is also simple.

- A €1/MWh increase in the natural gas price decreases the clean spark spread, but not the clean dark spread.
- A €1/MWh increase in the coal price decreases the clean dark spread, but not the clean spark spread.
- A €1/tCO_2 increase in the emissions allowance price decreases both clean spreads. However, it lowers the clean dark spread more than the clean spark spread since the carbon emissions factor for a coal-fired power plant is much higher than a natural gas-fired power plant.

Each of these can also have an indirect effect on the electricity price, which feeds back onto the set of spreads. Nevertheless, the relative impact of each change on the different clean spreads remains the same.

Price reporting agencies publish data on clean spark and clean dark spreads based on a benchmark fuel and its carbon content, together with a benchmark efficiency level. We had already seen this in Chapter 6, which showed a table of spark and clean spark spreads in the UK.

9.2.4 Factors Determining the Price of Pollution

In a cap-and-trade system, the market price of an allowance fluctuates with supply and demand, just as in any other market. There are many factors that impact the supply and demand of allowances and therefore the market price, including the following:

- Strong economic growth increases the demand for electricity, and therefore increases the demand for allowances. This increases the price of an allowance. Weak economic growth, or a major recession, decreases the price of an allowance.

- Fuel prices can affect the price of an allowance, although the exact effect depends upon the structure of the industry. However, in certain cases, the effect is easier to predict. An increase in the price of coal will typically shift generation to natural gas, lowering emissions and decreasing the price of allowances. Conversely, an increase in the price of natural gas can shift generation to coal, thereby raising emissions and increasing the price of allowances.
- Increased generation from wind and solar farms decreases emissions and decreases the price of allowances.

Keep in mind that this is the result of each factor individually, with all else being equal. In fact, they often occur in combination, in which case the final effect is difficult to determine.

The strength with which these factors determine the price of an allowance depends upon many details of the market rules. A good example is the right to bank an allowance. In our initial description of a cap-and-trade system, we discussed an annual cap on emissions. What happens as the end of the year arrives? In many systems, companies can carry forward any unused allowances and use them to cover emissions in later years. This is called **banking**. Whether banking should be allowed or not depends upon the type of pollution. CO_2 is a **stock pollutant**, meaning the damage is produced by the cumulative emissions over a long period of time. The flow of CO_2 in an individual year matters very little to the damage caused. Therefore, it makes sense to allow banking of allowances, which most carbon cap-and-trade systems do to some degree or another. Where allowances are fully bankable across time, only a sustained change in the factors cited above should impact the allowance price. One day of high wind resources, which decreases dispatch of fossil-fueled power plants and therefore emissions, will not change the allowance price noticeably. The unused allowances from that one day's operation is hardly a significant addition to the aggregate supply of allowances usable over some window of years. This is exactly how we should want it to work out, since CO_2 is a stock pollutant.

In contrast, a **flow pollutant** is one where the damages are produced by the level of emissions at each point in time, but where the cumulative emissions are not relevant. The classic examples are noise and light. In power markets, NO_x have some characteristics of flow emissions. This is because they are a precursor to the formation of ozone, which is the actual agent harming human health. The amount of ozone produced depends on the location of the emissions and their interaction with local volatile organic compounds (VOCs) and sunlight. In general, ozone creation is more of a problem during certain short spells of intense summertime weather. Therefore, the damage from nearby NOx emissions is greater in the summertime than the wintertime. We would not want to set up a system in which allowances for winter emissions can be banked and used in the summer. We want to specifically limit summertime emissions. This illustrates the complexity of properly pricing pollution. We will not elaborate on this complexity across different types of emissions.

The importance of banking for the determination of a CO_2 price can be seen when it is not allowed: this happened at the conclusion of the first phase of the EU-ETS, which covered emissions from 2005-2007. Figure 9.4 shows the spot price of a Phase 1 allowance from July 2006 through the end of the phase in December 2007. At the conclusion of Phase 1, once all emissions were tallied and matching allowances were submitted, any remaining allowances were worthless since they could not be used in future years. This is why the price collapsed throughout the end of 2006 and all of 2007 as it became clearer and clearer that all covered facilities had enough allowances to cover all emissions. For comparison, the figure also shows the futures price of a Phase 2 allowance deliverable in December 2008, which shows that 2008 emissions were still costly.

When banking is permitted, there is no significant price discrepancy across the seam defined by the end of a year or the end of a phase. In later years of the EU-ETS, banking has been permitted: a Phase 2 allowance, issued for one of the years between 2008 and 2012 could be banked to cover emissions in a Phase 3 year, such as 2013. Figure 9.5 shows the spot price of a Phase 2 allowance from July 2011 through the end of the phase in December 2012. The figure also shows the futures price of a Phase 3 allowance deliverable in December 2013. Notice that the futures price for a Phase 3 allowance tracks the spot price of a Phase 2 allowance very closely. Indeed, at the conclusion of Phase 2, in December 2012, although the phase was

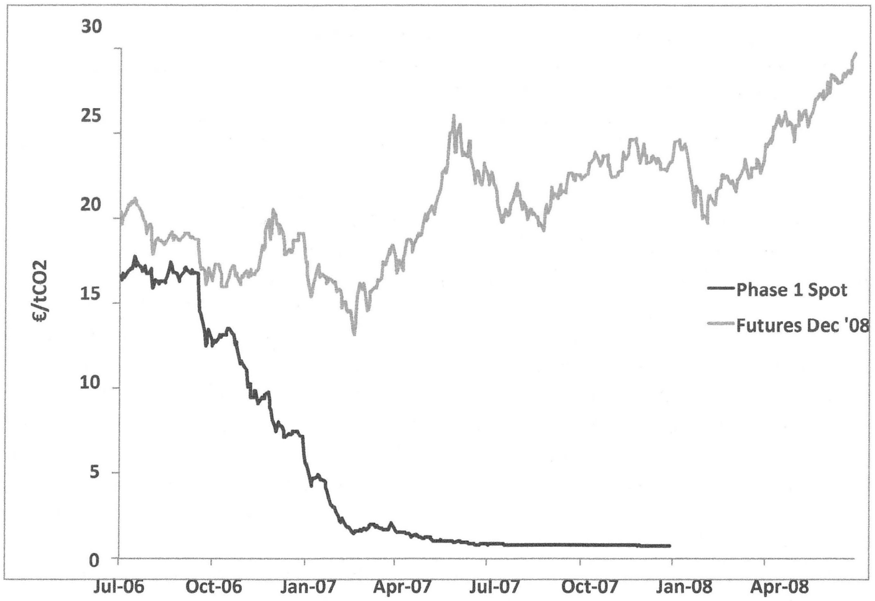

Figure 9.4: End of Phase Collapse of the Price for Phase 1 Allowances in the EU-ETS.

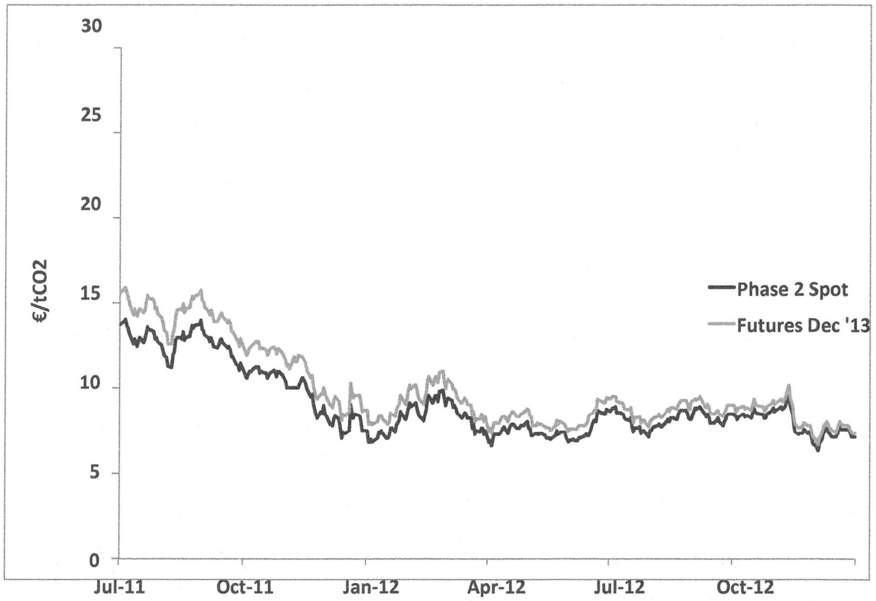

Figure 9.5: With Banking, the End of Phase 2 Allowance Price Tracks the Phase 3 Futures Price.

Table 9.4: Prices and Payments Under a Feed-In Tariff (FIT)

Load	GWh	10
Generation		
Wind	GWh	2
Other	GWh	8
Total	GWh	10
Price Paid to Generators		
Wholesale Clearing	€/MWh	30.00
FIT	€/MWh	35.00
Payments to Generators		
Wind	€	70,000
Other	€	240,000
Total	€	310,000
Price Paid by Load		
Wholesale Clearing	€/MWh	30.00
Surcharge	€/MWh	1.00
Total	€/MWh	31.00

coming to an end, a Phase 2 allowance still had value, and that value was almost exactly equal to the futures price for a Phase 3 allowance to be delivered one year later.

9.3 Markets for Clean Energy

An alternative to penalizing emissions is a policy of rewarding generation that has no emissions, i.e., 'clean' energy. This has proven especially popular with regard to the problem of reducing CO_2 emissions. Across the globe, governments have instituted a diverse array of policies designed to promote generation from non-emitting technologies–almost exclusively renewable technologies. These include:

- Fixing a premium price per unit of non-emitting electricity produced, which often goes by the label of a **feed-in tariff** (FIT) but also includes production tax credits and other channels for a government subsidy;
- Establishing a quota for non-emitting generation, which often goes by the label **renewable portfolio standards** (RPS);
- Fixing a premium price for non-emitting capacity, which is a variation on a capacity payment system–one that targets particular technologies; a premium can also be provided through subsidized financing programs;
- Establishing a quota for non-emitting capacity investments, which is a variation on a capacity market.

These diverse policies can also be implemented in combination.

Under a feed-in tariff (FIT), qualifying generators, such as wind or solar farms, receive dispatch priority. The wholesale market is only used to clear supply and demand for the remaining amount of generation needed. Non-qualifying generators receive the wholesale market clearing price, while qualifying generators receive the FIT. The price paid for qualifying energy can either be (i) set at a high, fixed absolute level, or (ii) set at a fixed premium to the wholesale market clearing price. To cover the cost of this premium, load pays a surcharge applied to purchases of all energy. Table 9.4 provides an illustrative example. Load

Table 9.5: Prices and Payments Under a Renewable Portfolio Standard with Tradable RECs.

Load	GWh	10
Generation		
Solar	GWh	2
Other	GWh	8
Total	GWh	10
Market Prices		
Wholesale Clearing	$/MWh	30.00
REC	$/MWh	5.00
Payments to Generators		
Wholesale energy	$	300,000
REC	$	10,000
Total	$	310,000
Price Paid by Load		
Wholesale energy	$/MWh	30.00
REC	$/MWh	1.00
Total	$/MWh	31.00

purchases in total 10 GWh, with 2 GWh supplied by wind generators under a FIT and 8 GWh supplied by other generators bidding into the wholesale market. The wholesale market clears the market for 8 GWh of energy at €30/MWh. The FIT pays a premium of €5/MWh above the clearing price, or €35/MWh, so the wind generators receive in total €70,000. The non-renewable generators receive the wholesale market clearing price for their 8 GWh which comes to a total of €240,000. Load must cover the total payments to generation, which are €310,000, and so must pay a total price of €31/MWh for the 100GWh. We can describe that as a wholesale market price of €30/MWh plus a surcharge of €1/MWh.

Under a renewable portfolio standard (RPS), a fraction of the total load must be supplied by qualifying generators. The rules for an RPS usually impose this requirement over a broad window of time, such as a year, so that in any given hourly market the fraction can vary widely. This creates two separate wholesale markets, one for qualifying generation and one for non-qualifying generation. Load serving entities (LSEs) negotiate separate power purchase agreements (PPAs) with qualifying generators in order to assure that they meet the fractional requirement. Assuming that the fraction required is significant, LSEs will have to pay a premium price to qualifying generators. The prices in the two separate markets fluctuate with the fluctuating aggregate demand and the separately fluctuating supply of each type of generation.

RPS rules often create tradable certificates known in some regions and countries as **renewable energy certificates** or RECs. Under a system with RECs, it is possible to recreate a single, centralized energy market where qualifying and non-qualifying generators compete head-to-head for the sale of energy. LSEs can purchase their energy in the bilateral or centralized market without regard to whether the provider is qualified or not. Qualifying generators receive certificates for every MWh of energy they produce, and these certificates can be sold to LSEs. LSEs must purchase certificates equal to the required fraction of the total load required under the RPS. A REC system still has two markets, but instead of markets for two different types of energy, it has a market for all types of energy and a market for the REC. The price of the REC is the premium paid to qualifying generators.

Table 9.5 provides an illustrative example. Load, and therefore total generation is 10 GWh. The fictional RPS mandates that 20% of the generation be from solar, which is 2 GWh. The way this mandate works is that LSEs must purchase RECs equal to 20% of their total load. The system operator awards RECs to solar generators for the power they produce, and the solar generators sell those RECs to LSEs. Table 9.5 shows a market price for RECs equal to $5.00/MWh. All generators compete against each other in the wholesale electricity market, and the table shows a market price for energy of $30.00/MWh. LSEs purchase all of their energy–whether generated by solar or by other generators–in the wholesale energy market, so in total they pay $300,000 for energy. In addition, LSEs purchase RECs at a total cost of $10,000.

Measuring the premium paid for qualifying generation can be challenging. Where an RPS operates without RECs, it is difficult to measure the premium. Qualifying generators capture their premium in the terms of their PPAs, which–as discussed in Chapter 6–require careful treatment if prices are to be compared with other PPAs and markets. Where an RPS operates with RECs and a centralized wholesale market, the centralized clearing price reflects the value of non-qualifying generation and, in principle, the REC price measures the premium paid for qualifying generation. In some jurisdictions, such as the U.S. states with RPS, REC markets are often fragmented and opaque so that the pricing is less transparent than it might be.

Tables 9.4 and 9.5 used the same basic input values, and we can see how the bottom line for the two systems is the same, whether using a FIT or RPS. The main difference is how the subsidy payments get made. Of course, our illustration does not capture how the two systems differ in the face of volatility. In the FIT, the price level or price premium is fixed, and the share of renewable generation this incentivizes is an outcome. In the RPS, the share is fixed, and the market price for RECs fluctuates. Of course, a government can revisit the level of the FIT over time if it wants to incentivize more or less generation. Similarly, a government can revisit the share mandated in an RPS which will cause the REC price to adjust accordingly. So, over time the two systems may be more similar than the short-run differences suggest.

Study Review

Some key terms introduced here:

- private costs
- public costs
- social costs
- externality
- internalize
- emissions charge, or fee, or tax
- emissions market
- European Union's Emission Trading System (EU-ETS)
- cap
- cap-and-trade system
- primary market
- secondary market
- carbon emissions factor
- clean spread
- clean spark spread
- clean dark spread
- banking
- stock pollutant
- flow pollutant
- feed-in tariff (FIT)
- renewable portfolio standard (RPS)
- renewable energy certificate (REC)

Electricity Markets & Coal

The broad areas of knowledge covered in this domain include:

Electricity

- Physical properties of electricity
    - Types of power generation (fossil fuel and renewable)
    - Transmission and distribution
- Electricity market economics
    - Base load, mid-merit, peak, and off-peak generation
    - Capacity factor, heat rate, and spark spread
    - Market data and price discovery
- Investing in generating capacity
- Electric energy markets and trading
    - Power pools (ISOs and RTOs) and bilateral trading
    - Contracts and structured solutions for energy markets
- Liberalized (deregulated) wholesale power market design
    - Energy markets (day-ahead vs. real-time) and balancing markets
    - Energy only vs. capacity markets
    - Ancillary services
    - Integration of renewable energy
- Global electricity markets and economic fundamentals

Coal

- Physical properties of coal
    - Types of coal, units of measure, and heat content
    - Benchmarks, contract specifications, and trading
    - Global coal markets and economic fundamentals
- Transportation